Preliminary Determination of Compliance

Valero Refining Company
102 Mw Power Plant
Phase I and Phase II

Bay Area Air Quality Management District
Applications Number 2488 and 2695

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Contents

PHASE I and Phase II

I. Introduction

This is the Preliminary Determination of Compliance (PDOC) for the Power Plant Project at the existing Valero Energy Corporation (Valero) refinery in Benicia, California: a 102-MW, refinery fuel gas/natural-gas fired, combined cycle power plant. The site is located in Block 25, Township 3 North, range 3 West of the Benicia Quadrangle, Solano County. Valero owns all land within 1000 feet of the proposed project site. The project site was selected because of its proximity to the electrical switch house and the refinery processing area. The site is sheltered from the community and should have minimal noise and visual impacts.

The proposed plant will consist of two 51 megawatt (MW) combined-cycle gas turbines with chillers, Heat Recovery Steam Generators (HRSG's), SCR and CO oxidation catalyst for emissions control, small package cooling tower and associated instrumentation, piping and wiring. The HRSG's will produce superheated steam at 600 psi for use in the refinery's processes and will result in the shut down of three existing package boilers (S-38, S-39, S-41).

Valero has submitted Applications number 2488 (Phase I) and 2695 (Phase II) for an Authority to Construct and Permit to Operate for this 102-megawatt power plant. Each application is to permit a gas turbine and heat recovery steam generator (HRSG) representing one half of the proposed project. This engineering evaluation covers both applications for purposes of permitting the 102 MW power plant. Since both applications are being processed concurrently, this PDOC covers the entire Valero Cogeneration project.

The gas turbine/HRSG systems will be fired on refinery fuel gas with natural gas backup.

A. Background

Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Preliminary Determination of Compliance (PDOC) document for the Valero Refinery Power Plant. It will also serve as the evaluation reports for the BAAQMD Authority to Construct applications #2488 and #2695. The PDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimated the impact of the project emissions on public health to be at an acceptable level. An air quality impact analysis (following PSD guidelines) was performed by Valero as required by the California

Energy Commission. Although the project net emissions do not require PSD analysis, the preliminary results are being reviewed by the District's Planning Department. The preliminary results indicate that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, this PDOC is subject to the public notice and public inspection requirements of District Regulation 2, Rule 2, Sections 406 and 407.

B. Project Description

1. Process Equipment

The applicant is proposing two combustion turbine power generation facilities with a maximum electrical output of 51 MW each. The first unit will produce electricity for the Valero refinery which will virtually eliminate the need for local utility power. The second unit will produce electricity that can be exported into the grid for use by other businesses and households in Northern California. The equipment to be permitted by the first and second unit is as follows:

<u>Phase I</u>

S-1030 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

S-1031 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

<u>Phase II</u>

S-1032 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

S-1033 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

EXEMPTION
A small package cooling water system will be used to dissipate heat from lube oil and the chiller. There is no steam condensing duty. The existing cooling tower is located just to the east of the new equipment, so the visual impact of any drift will not be discernable. The circulation rate will be 5,600 gpm. Makeup cooling water estimated at 70 gallons per minute will be obtained from the City of Benicia through existing lines. The configuration will be three cells, each of which will be 11 feet in diameter. The maximum air flow rate is 540,000 cfm. The maximum heat dissipation rate will be 40 MM Btu/hr, and the drift rate will be 0.005% of design flow.

Based on a water analysis from the City of Benicia, the cooling tower will emit the following compounds: Chlorine, Copper, Manganese, Nickel, Sulfate and zinc. As shown in the table below, the emissions from these compounds due to the new cooling tower is estimated to be 3.8 tons/year of particulate matter, with about 4/5 of these emissions coming from sulfates.

Cooling Tower Emissions

Compound	**Cooling Water Rate (gpm)**	**Drift Rate (%)**	**Emissions[1] (Lb/Hr)**	**Emissions[1] (TPY)**
Chlorine	5600	0.005	1.52E-01	6.66E-01
Copper	5600	0.005	3.50E-05	1.53E-04
Manganese	5600	0.005	4.06E-05	1.78E-04
Nickel	5600	0.005	1.68E-05	7.36E-05
Sulfate	5600	0.005	7.15E-01	3.13E+00
Zinc	5600	0.005	1.40E-05	6.14E-05
Total				3.80E+00

[1]The various compounds are below the toxic trigger level in Table 2-1-316. It must be mentioned that sulfates are not listed on the table. Nonetheless, these emissions were included in the Health Risk Assessment for the Valero's Cogeneration Project.

This Wet Cooling Tower is exempt from the District per Regulation 2-1-128.4 since it is not used for the evaporative cooling of refinery process water. It will emit less than 5 tons per year of particulates and does not trigger a toxic risk screen.

Exempt Wet Cooling Tower: 540,000 air flow rate, 5600 gpm water circulation rate (Exempt per Regulation 2-1-128.4: Water cooler tower not used for evaporative cooling of process water)

2. Air Pollution Control Strategies, BACT, and Equipment

The proposed power plant includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (NOx), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide (SO2), and particulate matter of less than 10 microns in diameter (PM10).

a. Selective Catalytic Reduction with Ammonia Injection for the Control of NOx

The gas turbines and HRSG duct burners each trigger BACT for NOx emissions. The gas turbines will be equipped with water injected combustors, which are designed to minimize NOx emissions. The HRSGs will be equipped with low-NOx duct burners, which are designed to minimize NOx emissions. In addition, the combined NOx emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. When firing refinery fuel gas or natural gas, the gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level NOx emission limit of 2.5 ppmvd @ 15 % O2 (three hour average).

b. Oxidation Catalyst to Minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The HRSGs will be equipped with a CO catalyst designed to catalytically oxidize the CO and POC produced from firing natural gas in the gas turbine and duct burner. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level CO emission limit of 10.0 ppmvd @ 15 % O2 with natural gas.

c. Oxidation Catalyst to Minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The HRSGs will be equipped with a CO catalyst to minimize CO and POC emissions. The gas turbine and HRSG duct burner combined exhaust are expected to achieve a BACT-level POC emission limit of 2.0 ppmvd @ 15 % O2 with natural gas fuel.

d. Amine Scrubber to Minimize SO2 and PM10 Emissions

The gas turbine and HRSG duct burners each trigger BACT for SO2 and PM10. The amount of SO2 emissions in the exhaust stream is a function of the sulfur levels in the combusted refinery gas. The total reduced sulfur (TRS) level presently in the refinery gas is 51 ppm. This level of TRS control is achieved through the use of an amine scrubber. PM10 emissions are minimized through the use of best combustion practices.

II. Facility Emissions

A. Maximum Hourly Mass Rate for Each Pollutant

1. NOx Maximum Hourly Mass Emissions Rate

The NOx emission limit for this proposed power plant is 2.5 ppmv. The NOx emissions from the turbines and HRSGs will be limited by permit condition to 2.5 ppmv, dry @ 15% O2.

Gas Turbine NOx Emissions Factor (S-1030 and S-1032)
This concentration is converted to a mass emission factor, for gas turbine firing only, with no duct burner firing as follows:

(2.5 ppmvd)(20.95-0)/(20.95 - 15) = 8.80 ppmv NOx, dry @ 0% O2

(8.8/1,000,000)(1 lbmol/385.3 dscf)(46.01 lb NO2/lbmol)(8600 dscf/MM Btu)
= 0.009 lb NO2/MM Btu

Duct Burner NOx Emissions Factor (S-1031 and S-1033)
This concentration is converted to a mass emission factor for the firing of the duct burners only as follows:

The additional NOx emissions from firing the duct burner are based on manufacturer emission factors (0.09 lb/MM Btu per J Zink) and at least 90% control of NOx emissions by the SCR. The emissions are calculated as follows:

Emission factor = 0.009 lb NO2/MMBtu

NOx Maximum Hourly Mass Emissions Rate
The NOx mass emission rate based on maximum hourly firing of the proposed power plant (S-1030, S-1031, S-1032, S-1033) is calculated as follows:

Given: 2 turbines (S-1030 and S-1032) @ 500 MM Btu/hr each = 1000 MM Btu/hr
2 HRSG (S-1031 and S-1033) @ 310 MM Btu/hr each = 620 MM Btu/hr
Total= 1620 MM Btu/hr

1620 MM Btu/hr x 0.009 lb NOx/hr = **14.58 lb NOx/hr**

2. CO Maximum Hourly Mass Emissions Rate

The CO emission limit for the proposed power plant is 10.0 ppmv, dry, @ 15% O2. This concentration is converted to a mass emission factor as follows:

(10.0 ppmvd)(20.95-0)/(20.95 - 15) = 35.21 ppmv CO, dry @ 0% O2

(35.21/1,000,000)(1 lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MMBtu)
= **0.022 lb CO/MMBtu**

The CO mass emission rate based on the maximum hourly firing rate of the two gas turbines and HRSGs (S-1030, S-1031, S-1032, S-1033) is calculated as follows:

(0.022 lb CO/MMBtu)(1620 MMBtu/hr) = **35.64 lb CO/hr**

3. POC Maximum Hourly Mass Emissions Rate

The POC emission limit for the proposed power plant is 2.0 ppmv, dry @ 15% O2. The volume concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95-0)/(20.95 - 15) = 7.04 ppmv POC as CH4, dry @ 0% O2

(7.04/1,000,000)(1 lbmol/385.3 dscf)(16 lb CH4/lbmol)(8600 dscf/MMBtu)
= **0.002515 lb POC as CH4/MM Btu**

The POC mass emission rate, with POC expressed as CH4, based on the maximum hourly firing rate of the two turbines and HRSGs (S-1030, S-1031, S-1032 and S-1033, is calculated as:

(0.002515 lb POC/MMBtu)(1620 MMBtu/hr) = **4.074 lb POC/hr**

4. SO2 Maximum Hourly Mass Emissions Rate

The SO2 emission from the proposed power plant consisting of two gas turbines and two HRSGs (S-1030, S-1031, S-1032, S-1033) will be limited by permit condition based on the following fuel concentration limits:

Rolling monthly Average: 51 ppm Total Reduced Sulfur (TRS)
24-hour Average (worst case): 100 ppm Hydrogen Sulfide (H2S)
Hourly Maximum (worst case): 160 ppm Hydrogen Sulfide (H2S)

Emission Factor for Refinery Fuel Gas

RFG (MM scf/hr	=	MM Btu/hr / Btu/scf
	=	1620 MM Btu/hr / 1251 Btu/scf (HHV)

= 1.295 MM scf/hr

$$SO2\ (\text{lb mole/hr}) = \frac{51 \times 1.295 \text{ scf/hr} \times 10^{6}}{106 \times 379.5 \text{ scf/lb mole}}$$

= 0.174 lb mole/hr

SO2 (lb/hr) = 0.174 lb mole/hr x 64 lb SO2/lb mole
= 11.138 lb/hr

$$SO2\ (\text{lb SO2/MM Btu}) = \frac{11.138 \text{ lb/hr}}{1620 \text{ MM Btu/hr}}$$

= **0.0069 lb SO2/MM Btu**

The SO2 hourly mass emission rates are calculated as follows:

Rolling Monthly Average @ 51 ppm TRS:
(0.0069 lb SO2/MMBtu)(1620 MMBtu/hr) = **11.138 lb SO2/hr**
or 1.404 ppm SO2 @ 15% O2 dry

24-hour Average @ 100 ppm H2S:
100/51 x 0.0069 = 0.0135 lb SO2/MM Btu
(0.0135 lb SO2/MMBtu)(1620 MMBtu/hr) = **21.87 lb SO2/hr**
or 2.747 ppm SOx @ 15% O2 dry

3-hour Average @ 160 ppm H2S:
160/51 x 0.0069 = 0.022 lb SO2/MM Btu
(0.022 lb SO2/MMBtu)(1620 MMBtu/hr) = **35.64 lb SO2/hr**
or 4.477 ppm SOx @ 15% O2 dry

5. PM10 Maximum Hourly Mass Emissions Rate

The PM10 emission from both the gas turbines and the HRSGs (S-1030, S-1031, S-1032, S-1033) will be limited by permit condition to 4.98 pounds per hour based on similar equipment's source test data.

The California Air Resources Board (CARB) has published a document titled "Guidance for Power Plant Siting and BACT'' dated July 1999. The document contains PM10 source test results for combined cycle and cogeneration gas turbines. This information was provided on Appendix C, Page 45 of that CARB document. That page has been excerpted from that document and is shown in **Appendix A**. As shown, two separate source tests were conducted on October 1995 and November 1996 on a General Electric LM6000 gas turbine with auxiliary-fired HRSG firing natural gas producing 42 MW. The source test results were 1.01 lb/hr and 2.08 lb/hr, respectively. Extrapolating to 51 MW yields 2.49 lb/hr PM10 using the higher source test number of 2.08 lb/hr PM10. Based on two cogeneration units, the hourly emissions rate would be doubled to

4.98 lb/hr PM10. Hence, based on these results, the maximum hourly mass emissions rate for PM10 for the power plant (S-1030, S-1031, S-1032, S-1033) will be 4.98 lb/hr.

6. Ammonia Emissions

The ammonia (NH_3) mass emission rate from the turbines and HRSGs (S-1030, S-1031, S-1032, S-1033) will be limited by permit condition to 10.0 ppmv, dry @ 15% O_2. The maximum NH_3 mass emission rate based on the maximum hourly firing rate of the turbine and HRSG is calculated as follows:

(0.013 lb NH_3/MMBtu)(1620 MMBtu/hr) = **21.06 lb NH_3/hr**

B. Maximum Daily Mass Rate for Each Pollutant

1. Maximum Daily Startup/Shut down Emissions, lb/day:

Maximum daily emissions are estimated based on 24 hours of worst-case emission rates. The worst-case daily emission rate is maximized on a day, which includes a one hour startup/shutdown, with the balance of the daily operations based on 100% load.

The start-up/shutdown (non-baseload) data is based on information previously provided by the manufacturer on a General Electric LM 6000, 51 MW to the CEC [Application 12809, United Golden Gate Power Plant (Data Request Response #2, Item #19, dated 12/15/00)]. A start-up is anticipated to take an average of ten minutes for the gas turbine. Hourly and start-up emission estimates were provided to the applicant from S&S Energy Products, a General Electric Power Systems Business. In the United Golden Gate Power Plant project, the District and the CEC staff, at that time, reviewed the emission estimates and concurred with the values submitted by the manufacturer. These estimated values will be used for this project since Valero will install an identical gas turbine.

General Electric Start-up/Stop Emissions, lb-turbine/hour-start/stop[1]

Source	**NOx**	**POC**	**CO**	**PM10**
S-1030	7.7	0.68	7.7	3.14
S-1031[2]	4.8	0.42	4.8	1.95
S-1032	7.7	0.68	7.7	3.14
S-1033[2]	4.8	0.42	4.8	1.95
Total	25.0	2.2	25.0	10.18

[1]Theoretical hourly emission rates for gas turbine based on allowable BACT concentration emission limits (at 100% load):

[2]Assuming same emissions rate for duct burners proportioned based on 310 MM Btu/hr as compared to 500 MM Btu/hour

2. Maximum Daily Mass Rate including Startup and Shutdown Emissions

Proposed Power Plant (S-1030, S-1031, S-1032, S-1033)
Maximum Operating Hourly Mass Emissions from Part II, A (1 through 5)
Maximum Startup and Shut down emissions from Part II, B.1 table
Startup and shutdown emissions limited to 1 hour. Start up and shudown
Emissions are included when the hourly rate exceeded the hourly baseload rate.

NOx = (25 lb/hr-start/stop) (1 start) + (14.58 lb/hr-baseload) (23 hr)
= 25 + 335.34 = **360.34 lb/day NOx**

CO = (35.64 lb/hr-baseload)(24 hr)
= 25 + 819.72 = **855.36 lb/day CO**

POC = (4.074 lb/hr-baseload)(24 hr)
= 2.2 + 93.702 = **97.776 lb/day POC**

PM10 = (10.18 lb/hr-start/stop) (1 start) + (4.98 lb/hr-baseload)(23 hr)
= 10.18 + 114.5 = **124.72 lb/highest day PM10**

SO2 @ 100 H2S Condition limit
SO2 = (21.87 lb/hr-baseload)(24 hr)
= **524.88 lb/highest day SO2**

C. Annual Emissions for Each Pollutant

Annual Emissions, tons/year:

Given: Maximum Hourly Firing Rate
2 turbines (S-1030 and S-1032) @ 500 MM Btu/hr each = 1000 MM Btu/hr
2 HRSG (S-1031 and S-1033) @ 310 MM Btu/hr each = 620 MM Btu/hr
Total = 1620 MM Btu/hr

Given: Anticipated Hourly Firing Rate (Annual Average)
2 turbines (S-1030 and S-1032) @ 465 MM Btu/hr each = 930 MM Btu/hr
2 HRSG (S-1031 and S-1033) @ 260 MM Btu/hr each = 520 MM Btu/hr
Total = 1450 MM Btu/hr

Based on year round operation at a nominal firing rate of 1450 MMBtu/hr.
365 days x 24 hrs/day = 8760 hrs/year
Use 8 hours for startup/shutdown (baseload operation).

NOx emissions calculation:
[(25 lb/hr x 8 hr/yr) + (0.009 lb NOx/MM Btu x 1450 MM Btu/hr x (8760 hr/yr - 8 hr/yr startup and shutdown))] [ton/2000 lb] = (200 + 114,213.6)/2000 = **57.207 tons/yr NOx**

CO emissions calculation:
[(25 lb/hr x 8 hr/yr) + (0.022 lb CO/MM Btu x 1450 MM Btu/hr x (8760 hr/yr - 8 hr/yr startup and shutdown))] [ton/2000 lb] = (200 + 279,188.8)/2000 = **139.694 tons/yr CO**

POC emissions calculation:
[(2.2 lb/hr x 8 hr/yr) + (0.002515 lb POC/MM Btu x 1450 MM Btu/hr x (8760 hr/yr - 8 hr/yr startup and shutdown))] [ton/2000 lb]
= (17.6 + 31,916.4)/2000 = **15.967 tons/yr POC**

SO2 emissions calculation:
[(0.0069 lb SO2/MM Btu x 1450 MM Btu/hr x (8752 hr/yr + 8 hr/yr startup and shutdown))] [ton/2000 lb]
= 87,643.8/2000 = **43.822 tons/yr SO2**

PM10 emissions calculation:
As shown in **Appendix A**., two separate source tests were conducted on October 1995 and November 1996 on a General Electric LM6000 gas turbine with auxiliary-fired HRSG firing natural gas producing 42 MW. The source test results were 1.01 lb/hr and 2.08 lb/hr, respectively. The average for the two source test is 1.55 lb/hr at 43 MW. For purposes of calculating the annual limit for the power plant, Valero has requested to use 1.55 lb/hr for each power train or 3.10 lb/hr for the Power Plant.

[(10.18 lb/hr x 8 hr/yr) + (3.1 lb/hr x (8760 - 8))] [1 ton/2000 lb]
= (81.44 + 27131.2)/2000 = **13.606 tons/yr**

Fugitive POC Emissions
Valero intends to install 600 valves, 4 compressors and 1800 flanges (connectors) to be used in this Power Plant Project. The POC emissions from the fugitive equipment were estimated at 0.945 ton/year. (See Table I). The emission factors were based on the CAPCOA correlation equations and screening values. The District approved the use of the CAPCOA correlation equations for determining the mass rate of emissions from fugitive equipment during the recent plant renewal cycle for Valero.

Table I
Permitted Maximum Annual Emissions, tons/yr

	NOx	**CO**	**POC**[1]	**SO2**	**PM10**
GT/HRSG's (S-1030, S-1031 S-1032, S-1033)	57.207	139.694	15.967	43.822	13.606
Fugitives			0.945		
Total	57.207	139.694	16.912	43.822	13.606

[1]Includes POC Emissions from fugitive components

	Count	lb/comp/day	lb/day	TPY
Valve	600	0.00179	1.074	0.196
Flange	1800	0.00166	2.988	0.545
Compressors	4	0.28	1.12	0.204
		Total		**0.945**

III. STATEMENT OF COMPLIANCE

A. Best Available Control Technology (BACT) Determinations

The following section includes BACT determinations by pollutant for the permitted sources of the proposed project.

Air Pollution Control Strategies and Equipment

The proposed facility includes sources that triggers the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (NOx), carbon monoxide (CO), precursor organic compounds (POC), sulfur dioxide (SO2), and particulate matter of less than 10 microns in diameter (PM10) because its emissions of these pollutants are above 10 pounds per highest day [Regulation 2-2-301].

The NOx, CO, and oxygen concentrations will be monitored continuously using a continuous emissions monitor (CEM). Therefore, emission concentrations of NOx and CO will be limited to parts per million (ppm) emissions concentrations in the permit conditions.

Nitrogen Oxides (NOx)

District BACT Guideline 89.1.6, dated October 18, 2000, specifies BACT1 (technologically feasible/cost-effective) for NOx for a combined-cycle gas turbine with a power rating $\geq$ 50 MW. BACT1 is a NOx emissions concentration not to exceed 2.5 ppmvd @ 15% O2, averaged over 1 hour for natural gas firing. This low emissions level has been achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with combustion modifications. BACT2 (achieved in practice) is a concentration not to exceed 3 ppmvd @ 15% O2 (averaged over 3 hours) when firing natural gas.

Since there is no BACT determination for gas turbines and HRSG's firing refinery fuel gas, a case by case BACT analysis has been performed. The District has determined that BACT for NOx for this project is an SCR system designed and demonstrated to achieve

2.5 ppmvd @ 15% O2 (three-hour average) when firing natural gas or refinery fuel gas. As discussed in **Appendix B**, the NOx emissions from a GE Frame 7 gas turbine is around 42 ppm. Based on a conservative cost effectiveness analysis, the cost effectiveness of installing SCR systems on two GE Frame 7 gas turbines being fired on refinery gas, and controlled using water injection, to further reduce the NOx to 2.5 ppm was $6726/ton NOx. This is much less than the maximum cost effectiveness guideline of $17,500/ ton NOx . Hence, it is cost effective and technologically feasible to limit the NOx to 2.5 ppm regardless of the fuel fired in this power plant.

Two relatively new technologies are capable of controlling NOx emissions from a gas turbine to 2 ppmv or below. These are SCONOx, manufactured by Goal Line Environmental Technologies, and XONON, manufactured by Catalytica, Inc. The District has reviewed these technologies to determine if they are appropriate for this application. It appears that while both of these innovative approaches to emission control show great promise for the future, and may currently be appropriate for other types of projects, neither option can be considered "technologically feasible" or "achieved in practice" for the type and size of equipment to be installed for this project.

SCONOx is the more established of the two technologies. This system uses a potassium carbonate coated catalyst to remove both NOx and CO, without the use a reagent such as ammonia. There is one system in commercial operation on a gas turbine of comparable size to this project.

However, SCONOx is installed on a combined-cycle electrical generation system, which typically has outlet temperatures below 400 degrees F. This project will have outlet temperatures exceeding 850 degrees F. We are not aware of any SCONOx applications on turbines with outlet temperatures that high, and Goal Line's Technical Paper describing the system lists acceptable temperature range as 300 to 700 degrees F. Based on this information, we do not believe that SCONOx represents a technologically feasible control option for this project.

XONON, developed by Catalytica, Inc., is another promising new technology for NOx emissions control. This technology uses a flameless catalyst located inside the combustion chamber itself, which allows for the combustion reaction to proceed at a lower temperature than in conventional turbines, thus minimizing the formation of NOx.

At the present time, the commercial availability of this technology is extremely limited. To date, we are aware of only one application, a 1.5 MW turbine in Santa Clara, California. There is no information available regarding the operation of such a system on a turbine the size of the one to be installed at this project, which is over 30 times larger. Based on this information, we do not believe that XONON represents a technologically feasible control option for this project.

Water will be injected into the turbine combustor to reduce NOx emissions at the combustor exhaust. Aqueous ammonia is injected into the SCR catalyst to control exiting stack emissions. The ammonia slip will be limited by permit condition to 10.0 ppmv. This is acceptable because the variability of refinery gas qualities require some allowance for ammonia slip. SCR for controlling NOx emissions represent a control technology that is technologically feasible, cost-effective, and achieved in practice in a wide variety of applications. This control technology represents BACT for this cogeneration project.

Carbon Monoxide (CO)

District BACT Guideline 89.1.6, dated October 18, 2000, specifies BACT (achieved in practice) for CO, firing natural gas, for a gas turbine with a power rating $\geq$ 50 MW, as CO emissions $\leq$ 10.0 ppmvd @ 15% O2, achieved through the use of an oxidation catalyst. CO emissions are also minimized through the use of best combustion practices. The CO emissions from the combustion turbine on natural gas or refinery fuel gas will be reduced through the use of an oxidation catalyst to less than 10 ppmvd CO @ 15% O2 averaged over any consecutive three-hour period.

BACT (technologically feasible/cost-effective) is specified for natural gas as a CO emission concentration of < 6 ppmvd @15% O2. This BACT specification is not specified for a gas turbine/HRSG operating mode firing natural gas or refinery fuel gas. Setting BACT at this 6 ppm concentration for the Valero Cogeneration Project is inappropriate since it has not been achieved in practice at all operating loads. It is recognized that when firing refinery fuel gas that the CO emissions directionally should be less because of the more complete combustion due to the higher heat content of the refinery fuel gas over natural gas (1251 Btu/cf vs 1050 Btu/cf). However, using conversion tables to go from ppm to mass, this empirically results in 1% less CO for refinery fuel gas over natural gas. This is a very small change. For purposes of this evaluation, CO emissions from the two fuels are treated the same.

When the Crockett Cogeneration facility was originally permitted in 1993 at a CO emission concentration limit of 5.9 ppmvd @ 15% O2, it established the technologically feasible/cost –effective BACT specification cited above. However, subsequent operation of the facility has shown that they cannot achieve this emission concentration under all operating modes and ambient conditions. Specifically, CO emissions exceed 5.9 ppmvd during minimum load operation under ambient conditions of low temperatures and high relative humidity and during peak load operations under ambient conditions of high temperature and moderate to high relative humidity. However, Crockett Cogeneration expects that the gas turbine will comply with a CO emission concentration limit of 10 ppmvd @ 15% O2 under all loads and ambient conditions with and without duct firing. Crockett has not employed steam injection augmentation during peak load/high temperature situations since the resulting CO emissions concentration would exceed the current emission limit of 5.9 ppmvd CO.

The Pittsburg District Energy Facility (PDEF) was recently issued a permit with a CO emission concentration limit of 6 ppmvd @ 15% O2 during all operating modes except for startup and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG and is predicated upon the use of an oxidation catalyst. Because PDEF proposed this limit, it was accepted as meeting BACT for CO. However, it is not considered achieve-in-practice BACT since it has not yet been demonstrated in actual operation.

Therefore, achieved in practice BACT for CO is deemed to be 10 ppmvd CO @15% O2, averaged over any consecutive three hour period, for the combined exhaust from the gas turbines and HRSG duct burners during all modes of operation except startup and shutdown. The applicant intends to achieve compliance with this limit through the use of a CO oxidation catalyst (A-61 and A-63).

Precursor Organic Compounds (POCs)

District BACT Guideline 89.1.6, dated 10/18/00, specifies BACT (achieved in practice) for POC, on natural gas, for a gas turbine with a power rating $\geq$ 50 MW, as POC emissions $\leq$ 2.0 ppmvd @ 15% O2, achieved through the use of an oxidation catalyst. The POC emissions from the combustion turbine on natural gas or refinery fuel gas will be reduced through the use of an oxidation catalyst to less than 2.0 ppmvd POC @ 15% O2.

Because CEMs for organic compounds only measure carbon (as C1), it is not possible to determine non-methane/ethane hydrocarbon concentrations on a real-time basis. As a result, a continuous emission concentration limitation as BACT for POC is not feasible. Therefore, BACT for POC is deemed to be a mass emission rate limitation to be verified by annual source testing. The POC emissions from the combustion turbine will be reduced to 2.0 ppmvd or less through the use of an oxidation catalyst. POC emissions are also minimized through the use of best combustion practices.

Sulfur Dioxide (SO2)

The proposed 102 MW power plant (S-1030, S-1031, S-1032, S-1033) will be fired on refinery fuel gas as well as natural gas. BACT on natural gas for SO2 emissions is a sulfur content not to exceed 1.0 grains/100scf achieved through the use of PUC-regulated grade natural gas. There is no BACT level for SO2 when firing refinery fuel gas. Thus, a case-by-case analysis will need to be performed. To control SO2 emissions, the sulfur levels in the refinery fuel gas will need to be at the lowest level practicable.

As part of the MTBE Manufacturing project (Permit Application 9425) to reduce SO2 emissions from the modified S-40 steam boiler, the existing MEA scrubbing system was modified to enhance its scrubbing capabilities for the removal of H2S and other sulfur compounds. The other sulfur compounds are made up of methyl mercaptans, dimethyl sulfide, dimethyl disulfide and carbonyl sulfide. These enhancements reduced the total reduced sulfur level for the entire refinery from 72 ppmv to 65 ppmv. It was determined to not be cost effective to obtain further reductions in this level. It must be mentioned that Valero explored four options to achieve greater reductions in sulfur levels in the refinery fuel gas. The options were:

1. Modify the existing MEA scrubbing system.

2. Add caustic scrubbing for only the fuel gas for the new and modified project.

3. Add caustic scrubbing for all of the fuel gas in the refinery.

4. Add caustic scrubbing for 60% of the refinery fuel gas.

The cost effectiveness of these various options were presented in the Clean Fuels Project, Application number 10392. The cost effectiveness analysis performed at that time is shown in **Appendix C**. The most cost effective option was number four: caustic scrubbing of 60% of the refinery fuel gas ($131,529/ton SO2). This exceeded the BACT1 cost effective standard of $18,300/ton by a factor of seven. Hence, BACT was declared at that time to be 65 ppm totaled reduced sulfur (TRS).

Valero has made a number of enhancement in their scrubber system in the last seven years that has further decreased the TRS level in the refinery fuel gas. Valero's current system is limited to 51 ppm TRS as a result of permitting a new steam boiler (S-237) in Application number 18888 in 1999. Thus, BACT was a TRS concentration not to exceed 51 ppmv, monthly average. This TRS level is equivalent to 0.0069 lb SO2/MMBtu.

For this project, based on the prior cost analysis for which option number 4 was 7 times greater than the maximum cost effectiveness number, BACT will be 51 ppm TRS (monthly average). Regarding H2S, it is limited to 100 ppmv, averaged over a 24 hour calendar day, and 160 ppmv H2S averaged over any 3-hour period.

Particulate Matter (PM10)

The proposed power plant (S-1030, S-1031, S-1032, S-1033) will be fired on refinery fuel gas as well as natural gas. BACT on natural gas for PM10 emissions is a sulfur content not to exceed 1.0 grains/100scf achieved through the use of PUC-regulated grade natural gas. There is no BACT level for PM10 when firing refinery fuel gas. Thus, a case-by-case analysis will need to be performed.

The California Air Resources Board (CARB) has published a document titled "Guidance for Power Plant Siting and BACT'' dated July 1999. The document contains PM10 source test results for combined cycle and cogeneration gas turbines. This information was provided on Appendix C, Page 45 of that CARB document. As mentioned earlier that page has been excerpted from that document and is shown in **Appendix A**. As shown, two separate source tests were conducted on October 1995 and November 1996 on a General Electric LM6000 gas turbine with auxiliary-fired HRSG firing natural gas producing 42 MW. The source test results were 1.01 lb/hr and 2.08 lb/hr, respectively.

Extrapolating to 51 MW yields 2.49 lb/hr PM10 using the higher source test number of 2.08 lb/hr PM10. Based on two cogeneration units, the hourly emissions rate would be doubled to 4.98 lb/hr PM10. Hence, based on these results, the maximum hourly mass emissions rate for PM10 for the power plant (S-1030, S-1031, S-1032, S-1033) will be 4.98 lb/hr.

B. Emissions Offsets

Pursuant to Regulation 2, Rule 2, Sections 302, federally-enforceable emission reduction credits are required for NOx and POC emissions at a ratio of 1.15: 1.0. Pursuant to Regulation 2, Rule 2, Section 303, federally enforceable emission reduction credits are required for SO2 and PM10 emissions at a ratio of 1.0 to 1.0. The applicant has demonstrated that it possesses sufficient valid offsets for this project and will submit certificates before the authority to construct is issued.

NOx Offsets:
Valero intends to shutdown three package boilers (S-38, S-39, S-41) which will no longer be needed to provide steam. The emission reductions from these sources will be used to offset the NOx emissions increase from this Power Plant Project. To determine the baseline for these boilers, Valero provided District staff with a printout showing the average hourly firing rate for each day for these units during 1998, 1999 and 2000. No data was provided for 2001. Since the baseline period per Regulation 2-2-605 is a three year period immediately preceding the date the application is deemed complete (April 2001), the three-year baseline period is April 1998 through March 2001. No data was provided by Valero for 2001. If Valero provides information to the district for this period prior to issuance of the Final Determination of Compliance, the numbers can be adjusted accordingly. The District anticipates that this will only make a slight change in the emissions reduction credit. The data for the 3-year baseline period is shown in **Appendix D.**

The average hourly firing rate for the S-38 is 66.372 MM Btu/hr. The average hourly firing rate for S-39 is 46.28 MM Btu/hour. The average hourly firing rate for S-41 is 79.562. The NOx emissions factor of 0.2153 Lb/MM Btu is based on a source test by Best Environmental on April 26 and April 27, 2001. See **Appendix E**.

Three Package Boilers (S-38, S-39, S-41)
(66.372 + 46.28 + 79.562) MM Btu/hour x 0.2153 Lb NOx/MM Btu x 8760 hours/yr x ton/2000 Lb = **181.261 tons/year**

BARCT Adjustment
Since the emissions reduction credit cannot exceed BARCT, the above numbers will need to be adjusted. Due to Regulation 9, Rule 10 which affect boilers, BARCT is 0.033 Lb/MM Btu for NOx emissions. Using the BARCT emissions factor, the allowable reduction is:

Three Package Boilers (S-38, S-39, S-41)
(66.372 + 46.28 + 79.562) MM Btu/hour x 0.033 lb NOx/MM Btu x 8760 hours/yr x ton/2000 Lb = **27.783 tons/year**

<u>SO2 Emissions Offset:</u>

Valero does not have any SO2 credits in the District's formal emissions bank. Attempts to purchase deposited SO2 credits from third parties has been fruitless. Due to the lack of purchasing SO2 credits in the Bay Area, Valero proposes to provide SO2 offsets by curtailing SO2 emissions from a specified group consisting of six sources. The group baseline is determined using the District procedures in Section 2-2-605 for calculating ERC baselines. The sources in the bubble had their SO2 emissions fully offset. The curtailment group will be managed to insure that there is no net increase in SO2 emissions above the group baseline after the new cogeneration project facilities are installed. Valero may add or delete sources from this curtailment group subject to approval of the District. The curtailment group and baseline for bubble is as follows:

Curtailment Group: Emission Sources	SO2 Baseline, Tons/year	Basis
S-237 Steam Boiler SG1032	8.6	Emissions fully offset (App. #18888)
S-220 Hot Oil Furnace F 4460	10.0	Emissions fully offset (App.#10392)
MTBE Ships	9.5	Emissions fully offset (App. #10392)
Phase I		
New GT/HRSG (S-1030 & S-1031)	0.0	New Source – Zero Baseline
Phase II		
New GT/HRSG (S-1032 & S-1033)	0.0	New Source – Zero Baseline
Total	28.1	Group Annual Limit

<u>SO2 Emissions Reduction from three boilers (S-38, S-39, S-41):</u>

Three Package Boilers (S-38, S-39, S-41)
(66.372 + 46.28 + 79.562) MM Btu/hour x 0.0046 lb SO2/MM Btu @ 34 ppm TRS x 8760 hours/yr x ton/2000 Lb = 3.873 tons/year

There is no RACT adjustment.

<u>POC emissions offset:</u>

The average hourly firing rate for the S-38 is 66.372 MM Btu/hr. The average hourly firing rate for S-39 is 46.28 MM Btu/hour. The average hourly firing rate for S-41 is 79.562. The POC emissions factor for S-38 and S-39 of 0.02 lb/MM Btu. The POC emissions factor for S-41 is 0.0002 lb/MM Btu. These factors came from source tests conducted on S-38 and S-41 by Best Environmental on April 26 and April 27, 2001. See **Appendix E**.

Three Package Boilers (S-38, S-39, S-41)
[(66.372 + 46.28) MM Btu/hour x 0.02 lb POC/MM Btu + (79.562 MM Btu/hr x 0.0002 lb POC/MM Btu)] x 8760 hours/yr x ton/2000 Lb = **9.938 tons/year**

There is no RACT adjustment for POC emissions.

PM10 Emissions Offset:

The average hourly firing rate for the S-38 is 66.372 MM Btu/hr. The average hourly firing rate for S-39 is 46.28 MM Btu/hour. The average hourly firing rate for S-41 is 79.562. The PM10 emissions factor for S-38 and S-39 of 0.021 lb/MM Btu. The POC emissions factor for S-41 is 0.012 lb/MM Btu. These factors came from source tests conducted on S-38 and S-41 by Best Environmental on April 26 and April 27, 2001. The emissions factor for S-38 is being used for S-39 since the boilers are similar. See test results in **Appendix E**.

Three Package Boilers (S-38, S-39, S-41)
[(66.372 + 46.28) MM Btu/hour x 0.021 lb PM10/MM Btu + (79.562 MM Btu/hr x 0.012 lb PM10/MM Btu)] x 8760 hours/yr x ton/2000 Lb = **14.546 tons/ye**ar

There is no RACT adjustment for PM10 emissions

CO Emissions Offset:

The average hourly firing rate for the S-38 is 66.372 MM Btu/hr. The average hourly firing rate for S-39 is 46.28 MM Btu/hour. The average hourly firing rate for S-41 is 79.562. The CO emissions factor for S-38 and S-39 of 0.4914 lb/MM Btu. These factors came from source tests conducted on S-38 and S-41 by Best Environmental on April 26 and April 27, 2001. See **Appendix E**. The CO emissions factor for S-41 is minimal based on source test. Valero has chosen not to seek any CO emissions reduction from S-41.

Three Package Boilers (S-38, S-39, S-41)
[(66.372 + 46.28) MM Btu/hour x 0.4914 lb CO/MM Btu] x 8760 hours/yr x ton/2000 Lb = **242.465 tons/year**

BARCT Adjustment

Per Regulation 9, Rule 7 for boilers, Best Available Retrofit Control Technology (BARCT) for CO emissions is 400 ppm @ 3% O2 or 0.287 lb CO/MM Btu.

[(66.372 + 46.28) MM Btu/hour x 0.287 lb CO/MM Btu] x 8760 hours/yr x ton/2000 Lb = **141.61 tons/year**

OFFSETS REQUIRED

Phase I and Phase II Emissions Increase

	NOx	CO	POC[1]	SO2	PM10
GT/HRSG's (S-1030, S-1031 S-1032, S-1033)	57.207	139.694	15.967	43.822	13.606
Fugitives			0.945		
Total	57.207	139.694	16.912	43.822	13.606

Contemporaneous Emissions reduction Credits

	NOx	CO	POC	SO2	PM10
S-38, S-39, S-41	-27.783	-141.61	-9.938	-3.873	-14.546
Total	-27.783	-141.61	-9.938	-3.873	-14.546

Remaining Offsets Needed

	NOx	CO	POC	SO2	PM10
GT/HRSG Fugitives	29.424	N/A	6.574	39.949	-0.94
Offset Ratio	1.15	N/A	1.15	1.0	1.0
Total	33.838[1]	N/A	7.56[2]	Curtailment	-0.94[3]

[1]Valero will surrender banking certificate #703 having NOx credits of 31.418 to satisfy this offset obligation and banking certificate # 682 having POC credits of 14.769 tons.

[2]Valero will surrender banking certificate #682 having POC credits of 14.769 tons.

[3]Valero has requested in accordance with Regulation 2-2-606.2 that a Banking Certificate be issued for the remaining credits when the S-38, S-39 and S-41 boilers have been shutdown.

C. PSD Air Quality Air Impact Analysis

Pursuant to Regulation 2-2-304.1, a PSD air quality analysis is not required. The project emissions shown in table list the RACT adjusted project emissions for both Phase I and Phase II and demonstrates that PSD is not applicable.

Comparison of Project Emissions Increases After Adjustment for RACT with PSD Trigger Level

Pollutant	Cumulative Increase (tons/year)	RACT Adjusted Emission Reductions (tons/year)	Difference (tons/year)	PSD Trigger Level (tons/year)	PSD Trigger (yes/No)
Nitrogen Oxides (as NO_2)	57.207	168.4	-111.193	40	No
Carbon Monoxide	139.694	141.61	-1.916	100	No
Precursor Organic Compounds	N/A	N/A	N/A	N/A	N/A
Particulate Matter (PM_{10})	13.606	14.546	-0.94	15	No
Sulfur Dioxide	43.822	3.873	39.949	40	No

Includes emissions from two gas turbines and heat recovery steam generators

Even though modeling is not triggered per the District's regulation, the California Energy Commissions required the modeling be performed for NOx, SO2, PM10 and CO. The modeling results are shown in **Appendix F**. Except for PM10 emissions, the results show that the cogeneration project will not interfere with the attainment or maintenance of the national ambient air quality standard (NAAQS). The total predicted background PM10 concentration for 24 hours exceeded the NAAQS (86 micrograms/cubic meter as compared to the standard of 50 micrograms/ cubic meter). The PM10 emissions for this cogeneration project will be nearly mitigated by the shutdown of three package steam boilers (S-38, S-39 and S-41).

D. Health Risk Assessment

A health risk assessment was conducted and reviewed by District staff. The health risk analysis considered toxic emissions from both turbines and the cooling tower. The maximum potential lifetime cancer risk for this project is estimated to be insignificant, i.e., less than 1.0E-06 (1.0 in one million). The results of the HRA are provided in **Appendix G** and are summarized below.

	Cancer Risk Maximum Screening Value[1]	**Maximum Chronic Hazard Index**	**Maximum Acute Hazard Index**
Total Risk	**0.9 E-06**	**0.1**	**0.03**
Significance criteria	**1.0 E-06**	**1.0**	**1.0**

[1]Cancer risk based on the average of five years of data

Publication and Public Comment

This Preliminary Determination of Compliance (PDOC) is subject to the publication and public comment requirements of sections 2-2-406 and 2-2-407 per section 2-3-404. The District will publish and solicit comments on the PDOC. We will consider all comments made on the PDOC during the public comment period, and will address all substantial comments made before issuing the Final DOC. In addition, the CEQA Analysis that will be led by the California Energy Commission will include hearings to allow the public to provide their comments on the project.

CEQA Analysis

For this project, the Lead Agency under the California Environmental Quality Act (CEQA) is the California Energy Commission (CEC). The District will not authorize the installation or operation of any proposed new or modified source, the permitting of which is subject to CEQA, until all of the requirements of CEQA have been satisfied. Per District Regulation 2-1-310, this project is not exempt from the requirements of CEQA because it is not ministerial and it is not an exempted source category.

To fulfill the CEQA-related information requirements of District Regulation 2-1-426.2.6, the applicant has submitted to the District information that shows that the CEC has assumed the role of Lead Agency for this project with respect to CEQA.

Valero filed the original Application for Certification (AFC) for Phase I and Phase II of the Valero Power Plant Project on May 7, 2001. The CEC staff has now begun its independent data discovery and analysis phases. These phases will include a number of public workshops and hearings. Under the terms of Public Resources Code section 25552, the CEC's overall review process must be completed within four months from June 6, 2001, the date that the AFC was determined to be data adequate, unless a later date is agreed to by the CEC and the applicant. The completion date for the CEC is on or about October 6, 2001.

Environmental Impacts of Ammonia Slip from the Use of SCR:

Aqueous ammonia will be used as the reagent in the SCR system. Deliveries will be made by tanker trucks and stored in an existing 546,000-gallon aboveground storage tank. Gas turbines using SCR have typically been limited to 10 ppmv, however single-digit levels for ammonia slip have been proposed and guaranteed by some control equipment vendors for large combined-cycle gas turbines.

In the June 1999 California Air Resources Board (CARB) "Guidelines for Power Plant Siting and Best Available Control Technology", CARB staff stated that "To date, Massachusetts has permitted two large gas turbine power plants using SCR with 2 ppmvd ammonia slip limits. Given the potential for health impacts and increase in PM10 and PM2.5, districts should ensure that ammonia emissions are minimized from projects using SCR. They recommend that districts consider establishing ammonia slip levels below 5 ppmvd at 15% oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip."

The District is not aware of any such ammonia slip guarantees for combined-cycle turbines that are required to meet a stringent limit of 2.5 ppmv NOx @ 15% O2, averaged over 1 hour, plus meet the strict limit of 5.0 ppmv ammonia slip when firing natural gas. Since Valero will be firing refinery fuel gas, data in this type of service is limited and the degree of ammonia in this type of service is speculative.. However, if any substantial data is provided to the District, prior to issuance of the Permit to Operate for this project, that clearly demonstrates that this combined-cycle gas turbine controlled by SCR should be limited to below 10.0 ppmv ammonia slip when firing refinery gas, the District will consider lowering the ammonia slip limit accordingly.

A health risk assessment by the District using air dispersion modeling showed an acute hazard index of 0.3 and a chronic hazard index of 0.1 which included the ammonia slip emissions. In accordance with the District Toxic Risk Management Policy and currently accepted practice, an acute hazard index of less than 1.0 and a chronic hazard index of less than 1.0 are considered acceptable. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulate, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the District's Planning Division, that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter. This potential environmental impact is not considered a sufficient reason to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The applicant will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. Therefore, the potential environmental impact due to aqueous ammonia storage at this facility does not justify the elimination of SCR as a control alternative.

E. Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the air quality impact analysis is designed to insure that the proposed facility will comply with this Regulation.

Regulation 2, Rule 1, Sections 301 and 302:
Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the applicant has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1030, Gas Turbine.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-101, this rule applies to power plants for which a Notice of Initiation or Application for Certification has been accepted by the California Energy Commission (CEC). On May 4, 2001, Valero submitted an Application for Certification (AFC) for Phase I and Phase II of the Power Plant Project. The CEC has assigned the project Docket No. 01-AFC-5 and conducted a hearing for data adequacy on June 6, 2001.

The procedural requirements in Regulation 2, Rule 3 will be met before issuance of the Final Determination of Compliance.

Regulation 2, Rule 7: Acid Rain

> Per the definition of Phase II Acid Rain Facility in Regulation 2-6-217.1, this facility is a Phase II Acid Rain Facility. Regulation 2-6-302 requires that the facility shall undergo major facility review in accordance with the requirements of this rule, even if such facility is not classified as a major facility under Section 2-6-212. All Phase II acid rain facilities shall comply with the requirements of Sections 405, 406, 408, 409, 411, and 412 of this rule.

This project will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72, 73, and 75. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75.

District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72 and administers the program in concert with the Title V Operating Permits Program (Rule 2-6).

The facility must obtain an Acid Rain Permit from the BAAQMD prior to the date on which the unit commences operation. We have been delegated authority for Acid Rain permits.

The project will be subject to the following general requirements under the acid rain program:

- Duty to apply for an Acid Rain Permit.
- Compliance with SO_2 and NO_x emission limits.
- Duty to obtain required SO_2 allowances.
- Duty to install, operate and certify Continuous Emission Monitoring Systems (CEMs) to demonstrate compliance with the acid rain requirements.

The applicant will meet the SO_2 allowances and will perform the required emission monitoring. Monitoring plans will be submitted as required by EPA rules.

Regulation 6: Particulate Matter and Visible Emissions

Through the use of water-injected low-NOx burner technology and proper combustion practices, the combustion of refinery fuel gas at the proposed gas turbine is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume.

Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the proposed SCR system will each be limited by permit condition to 10 ppmvd @ 15% O2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Rule 18 Equipment Leaks

The fugitive equipment should comply with the Standards of Regulation 8, Rule 18 for Valves, Compressors and Flanges. The leak standards for valves, compressors and flanges will be 100 ppm, 500 ppm and 100 ppm, respectively.

VALVES -- Most valves will use graphite packing which is the best material available to achieve low emissions in a wide variety of applications. All valves will be required to meet a leak rate of no more than 100 ppm.

COMPRESSORS -- The compressors will be equipped with double mechanical seals and an approved Inspection and Maintenance (I&M) Program to reduce emissions from compressors seals. A leak standard of 500 PPM will be required to be met.

FLANGES -- The flanges will use graphite or equivalent designed flange gaskets to reduce POC fugitive emissions. A leak standard of 100 PPM will be required to be met.

Regulation 9: Inorganic Gaseous Pollutants

Regulation 9, Rule 1, Sulfur Dioxide

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level SO2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits SO2 emissions in excess of 300 ppm (dry). The gas turbine is not expected to contribute to noncompliance with ground level SO2 concentrations and should easily comply with section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The proposed combustion gas turbine shall comply with the Regulation 9-3-303 NOx limit of 125 ppm @ 15% O2.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because the proposed combustion gas turbine will be limited by permit condition to NOx emissions of 4.4 ppmvd @ 15% O2, when firing refinery gas, it is expected to comply with the Regulation 9-9-301.3 NOx limitation of 9 ppmvd @ 15% O2.

Regulation 9, Rule 11, Nitrogen Oxides and Carbon Monoxide from Electric Power Generating Steam Boilers

This rule may apply, depending on the owner's final status with the PUC.

Regulation 10: New Source Performance Standards (NSPS)

This regulation incorporates the federal NSPS.

Subpart A General Provisions provides the general framework for NSPS. Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units does apply because this project utilizes duct burners. The NOx limit of 85 ppm will easily be met.

Subpart GG Standards of Performance for Stationary Gas Turbines - contains a NOx emission limit in part 60.332 (a)(2) of 50 ppmv at 15% O2, dry, 3-hour average, as well as monitoring and testing requirements for combustion turbines. The project emissions will be well below the applicable NOx emissions limits. The applicant will comply with emission and fuel monitoring requirements, and monitoring plans will be submitted, as required.

Section 112 of the Clean Air Act, National Emission Standards for Hazardous Air Pollutants (NESHAP)

These standards are contained in 40 CFR Parts 61 and 63 and are not applicable to the proposed project.

IV Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb./hr) will ensure that daily and annual emission rate limitations are not exceeded.

Compliance with CO, SOx, and NOx limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. Compliance with POC and PM10 mass emission limits will be demonstrated by annual source testing.

In addition to permit conditions that apply to as designed operation of each CTG/HRSG power train, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and oxidation catalysts fully operational. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 3 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedance of any short-term applicable ambient air quality standard.

Permit Conditions

Definitions:

1-hour period:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in Btu/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.
Firing Hours:	Period of time during which fuel, other than pilot gas, is flowing to a unit, measured in fifteen-minute increments.
MM Btu:	million British thermal units
Gas Turbine Start-up Mode:	The lesser of the first 256 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d).
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(b) through 20(d) until termination of fuel flow to the Gas Turbine.
Corrected Concentration:	The concentration of any pollutant (generally NOx, CO, or NH3) corrected to a standard stack gas oxygen concentration. For emission point P-60 (combined exhaust of S-1030 Gas Turbine and S-1031 HRSG duct burners) and emission point P-62 (combined exhaust of S-1032 Gas

	Turbine and S-1033 HRSG duct burners) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis.
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, and associated electrical delivery systems.
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation.

Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager

Valero Power Plant Project – S-1030, S-1031, S-1032, S-1033
Conditions for the Approval of the Authority to Construct and Permit to Operate

1. Prior to the approval of the Authority to Construct for S-1030, S-1031,S-1032 and S-1033, the owner will provide the following offsets: (Basis: NOx and POC)

   NOx: 33.838 TPY from Certificate # 703 and #682
   POC: 7.56 TPY from Certificate #682

2. For SO2 emissions offsets, a curtailment group is established as follows: (Basis: SO2 offsets)

Curtailment Group:

Emission Sources	Baseline, SO2 Tons/year	
S-237 Steam Boiler SG1032	8.6	
S-220 Hot Oil Furnace F 4460	10.0	
MTBE Ships	9.5	
Phase I New GT/HRSG (S-1030 & S-1031)	0.0	
Phase II New GT/HRSG (S-1032 & S-1033)	0.0	
Total	28.1	Group Annual Limit

a. SO2 emissions from the Curtailment Group will not exceed 28.1 TPY for any consecutive four quarter period.

b. Emissions will be calculated using fuel flow meters and the TRS Gas Chromatograph CEM's data, or stack SO2 CEMS and flow data, or other District approved methods.

c. Owner can deposit any valid ERC certificate into the group as a credit, at any time.

d. A quarterly report of the group emissions will be submitted to the District, in a District approved format, to document compliance.

e. Sources may be added to or deleted from the group at Valero's request subject to District approval. This process will increase or decrease the total emission limit for the group by the source's base line amount, as calculated per the District's ERC procedures found in Section 405 of Regulation 2, Rule 2.

Conditions for the Commissioning Period: S-1030, S-1031, S-1032, S-1033

3. The owner/operator of the proposed power plant (S-1030, S-1031, S-1032, S-1033) shall minimize emissions of carbon monoxide and nitrogen oxides from these sources to the maximum extent possible during the commissioning period. Conditions 3 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, the remaining conditions shall apply after the commissioning period has ended.

4. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the Gas Turbine combustors and Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

5. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-60/A-62 SCR System, and A-61/A-63 CO Oxidation Catalyst System shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-1030 Gas Turbine and S-1031 Heat Recovery Steam Generator.

6. Coincident with the as designed operation of A-60/62 SCR System, the Gas Turbines (S-1030 and S-1032) and the HRSG (S-1031 and S-1033) shall comply with the NOx and CO emission limitations specified in conditions 18(a) through 18(b).

7. The owner/operator shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1030 and S-1032 Gas Turbine describing the procedures to be followed during the commissioning of the gas turbine and HRSG. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1030 and S-1032) and HRSGs (S-1031 and S-1033) without abatement by their respective SCR and CO Catalyst Systems.

8. During the commissioning period, the owner/operator shall demonstrate compliance with conditions 10 through 12 through the use of properly operated, and maintained continuous emission monitors and data recorders for the following parameters:

- firing hours for the gas turbine and HRSG
- fuel flow rates through the train
- stack gas nitrogen oxide (and oxygen) emission concentrations at P-60/P-62
- stack gas carbon monoxide emission concentrations P-60/P-62
- stack gas SO2 emission concentrations at P-60/P-62 or fuel TRS/H2S concentrations.

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1030 and S-1032) and HRSGs (S-1031 and S-1033). The owner/operator shall use District-approved methods to calculate heat input rates, NOx mass emission rates, carbon monoxide mass emission rates, SOx mass emission rates, and emission concentrations of NOx, SOx, and CO, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

9. The District-approved continuous emission monitors specified in condition 8 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-1030 and S-1032) and Heat Recovery Steam Generator (S-1031 and S-1033). After first firing of the turbine, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO, SOx, and NOx emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

10. The total number of firing hours of S-1030/S-1032 Gas Turbines and S-1031/S-1033 Heat Recovery Steam Generators without abatement of nitrogen oxide emissions by A-60/A-62 SCR System and/or A-61/A-63 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-1030/S-1032 Gas Turbine and S-1031/S-1033 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

11. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-1030 and S-1032) and Heat Recovery Steam Generators (S-1031 and S-1033) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 22

12. Combined pollutant mass emissions from the Gas Turbine (S-1030 and S-1032) and Heat Recovery Steam Generators (S-1031 and S-1033) shall not exceed the following limits during the commissioning period. These emission limits shall

include emissions resulting from the start-up and shutdown of the Gas Turbines and HRSGs (S-1030, S-1031, S-1032 & S-1033).

NOx (as NO2)	360.34 pounds per calendar day
CO	855.36 pounds per calendar day
POC (as CH4)	97.776 pounds per calendar day
PM10	124.72 pounds per calendar day
SO2	524.88 pounds per calendar day

<u>Conditions for the Operation of Gas Turbines (S-1030 and S-1032) and the Heat Recovery Steam Generators (HRSG; S-1031 and S-1033)</u>

13. The Gas Turbines (S-1030 and S-1032) and HRSG Duct Burners (S-1031 and S-1033) shall be fired on refinery fuel or natural gas. (Basis: BACT for SO2 and PM10)

14. The combined heat input rate to the power train consisting of a Gas Turbine and its associated HRSG (S-1030 and S-1031 or S-1032 and S-1033) shall each not exceed 810 MM Btu per hour, averaged over any rolling 3-hour period. The gas turbine in each power train (S-1030 or S-1032) shall not exceed 500 MM Btu/hr. (Basis: PSD for NOx)

15. The combined heat input rate to the power train consisting of a Gas Turbine and its associated HRSG (S-1030 and S-1031 or S-1032 and S-1033) shall each not exceed 19,440 MM Btu per calendar day. (Basis: PSD for PM10)

16. The combined cumulative heat input rate for the Gas Turbines (S-1030 and S-1032) and the HRSGs (S-1031 and S-1033) shall not exceed 12,702,000 MM Btu per year. (Basis: Offsets)

17. S-1030/S-1032 Gas Turbines and S-1031/S-1033 HRSGs shall be abated by the properly operated and properly maintained A-60/A-62 Selective Catalytic Reduction (SCR) System and A-61/A-63 CO Oxidation Catalyst System whenever fuel is combusted at those sources and the catalyst bed has reached minimum operating temperature.
(Basis: BACT for NOx)

18. The Gas Turbines (S-1030 and S-1032) and HRSGs (S-1031 and S-1033) when firing natural gas exclusively shall comply with requirements (a) through (f) under all operating scenarios, including duct burner firing mode. Requirements (a) through (f) do not apply during a gas turbine start-up or shutdown. (Basis: BACT, PSD, and Toxic Risk Management Policy)

(a) Emissions of nitrogen oxides (NOx) at emission points P-60 or P-62 shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O2, averaged over any one hour period. (Basis: BACT for NOx when firing natural gas)

(b) The carbon monoxide emissions concentration at P-60 or P-62 shall not exceed 10 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-clock hour period. (Basis: BACT for CO when firing natural gas)

(c) Ammonia (NH3) emission concentrations at P-60 or P-62 shall not exceed 10 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. Compliance with this ammonia emission concentration limit will be demonstrated by initial source test. (Basis: Toxics)

(d) Precursor organic compound (POC) mass emissions (as CH4) from P-60 or P-62 shall not exceed 2.0372 pounds per hour or 0.002515 Lb/MM Btu of natural gas fired. (Basis: BACT for POC when firing natural gas)

(e) Sulfur dioxide (SO2) mass emissions at P-60 or P-62 shall not exceed 1.134 pounds per hour (3-hour average) (BACT) or 0.0014 Lb/MM Btu of natural gas fired. (Basis: BACT for SO2 when firing natural gas),

(f) Particulate matter (PM10) mass emissions at P-60 or P-62 shall not exceed 4.795 pounds per hour or 0.00592 Lb/MM Btu of natural gas fired. (Basis: BACT for PM10 when firing natural gas)

19. The Gas Turbines (S-1030 and S-1032) and HRSGs (S-1031 and S-1033) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (Basis: BACT, PSD, and Toxic Risk Management Policy)

(a) Emissions of nitrogen oxides (NOx), calculated in accordance with District approved methods as NO2, at P-60 (the combined exhaust point for the S-1030 Gas Turbine and the S-1031 HRSG after abatement by A-60 SCR System) shall not exceed 10.74 pounds per clock hour (Basis: BACT for NOx, Offsets)

(b) Emissions of nitrogen oxides (NOx) at emission points P-60 or P-62 shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O2, averaged over any 3-clock hour period. (Basis: BACT for NOx)

(c) Carbon monoxide mass emissions at P-60 or P-62 shall not exceed 17.82 pounds per clock hour, averaged over any rolling 3-hour period. (Basis: PSD for CO)

(d) The carbon monoxide emission concentration at P-60 or P-62 shall not exceed 10 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-clock hour period. This emission limitation shall be subject to adjustment based on the initial source test results. (Basis: BACT for CO)

(e) Ammonia (NH3) emission concentrations at P-60 or P-62 shall not exceed 10 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. Compliance with this ammonia emission concentration limit will be demonstrated by initial source test. (Basis: Toxics)

(f) Precursor organic compound (POC) mass emissions (as CH4) at P-60 or P-62 shall not exceed 2.037 pounds per hour. (Basis: BACT)

(g) Sulfur dioxide (SO2) mass emissions at P-60 or P-62 shall not exceed 5.569 pounds per hour (rolling monthly average) (BACT) nor 10.94 pounds per hour (24 hour average) nor 17.82 pounds per hour (3 hour average). (Basis: NSPS)

Either fuel sulfur (TRS) or stack SO2 must be monitored and meet the following limitation, as appropriate: Sulfur dioxide (SO2) concentrations at P-60 or P-62 shall not exceed 1.404 ppmv, on a dry basis, corrected to 15% O2 on a rolling four quarter average, nor 2.747 ppmv, on a dry basis, corrected to 15% O2 on a 24 hour average, nor 4.477 ppmv, on a dry basis, corrected to 15% O2 on a three hour average.

SO2 concentrations in refinery fuel gas shall not exceed 51 ppm TRS on a rolling monthly average, nor 100 ppm H2S on a 24 hour average, nor 160 ppm H2S on any three hour average. (Basis: NSPS, BACT, Offsets)

(h) Particulate matter (PM10) mass emissions from P-60 and P-62 shall not exceed 4.98 per hour nor 3.10 pounds per hour on a rolling monthly average. This limit is subject to revision based on the results of the initial source test. Demonstration of compliance will be based on source test results. (Basis: BACT for PM10)

20. A District approved initial source test will be commenced within 60 days of startup to demonstrate compliance with Conditions number 18 and 19. The test results will be forwarded to the District within 60 days of completion of the field test. The test should verify emission compliance near maximum firing on:

1. Gas Turbine firing natural gas only
2. Gas Turbine and HRSG firing natural gas only
3. Gas Turbine firing refinery fuel gas only
4. Gas Turbine and HRSG firing refinery fuel gas only.

(Basis: Compliance Verification with BACT)

21. The owner will conduct annual source tests and submit the results within 60 days of the test's completion. These tests will demonstrate compliance with POC and PM10 emission limits in conditions 19 (f) and 19 (h). (Basis: Compliance Monitoring)

22. Total emissions from S-1030, S-1031, S-1032 & S-1033 shall not exceed the following annual limits:
(Basis: Cumulative Increase, Offsets, PSD)

NOx - 57.207 TPY (based on CEM data)
POC – 16.512 TPY (based on source test results plus fugitive emissions of 0.945 TPY)
PM10 – 13.606 TPY (based on source test results)
SOx – 43.822 (based on quarterly curtailment group compliance under condition # 2)
CO - 139.694 TPY (based on CEM data)

An annual report will be prepared by owner and submitted to the District documenting compliance with these annual limitations to mass emissions. (Basis: Compliance Monitoring)

23. To demonstrate compliance with conditions 19(f), 19(g) and 19(h), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM10) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO2) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM10, and SO2 emissions shall be summarized for: the combined power train: [Gas Turbine (S-1030)/HRSG (S-1031)] or [Gas Turbine (S-1032)/HRSG (S-1033)]

(b) On a daily basis, the 365 day rolling average cumulative total POC, PM10, and SO2 mass emissions, for both power trains: [Gas Turbine (S-1030)/HRSG (S-1031)] or [Gas Turbine (S-1032)/HRSG (S-1033)].

(Basis: Offsets, PSD, Cumulative Increase)

24. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM10 emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District within 60 days of conducting the tests. (Basis: Source Test Compliance Verification)

25. The owner/operator shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Basis: Regulation 2-6-502)

26. The owner/operator shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Basis: Regulation 2-6-501)

27. The owner/operator shall notify the District of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition.–(Basis: Regulation 2-1-403)

28. The stack height of emission points P-60 and P-62-shall each be at least 80 feet above grade level at the stack base. (Basis: PSD, TRMP)

29. The Owner/Operator shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Basis: Regulation 1-501)

30. Within 180 days of the issuance of the Authority to Construct, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Basis: Regulation 1-501)

31. The Cogeneration project shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Basis: Regulation 2, Rule 7)

32. The startup period for the S-1030 and S-1032 Gas Turbines shall last for no more than one hour.

33. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of the Valero Power Plant shall submit an application to the BAAQMD for a significant

revision to the Major Facility Review Permit prior to commencing operation. (Basis: Regulation 2-6-404.3)

34. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Valero Power Plant shall not operate either of the gas turbines until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Basis: Regulation 2, Rule 7)

Fugitive Equipment

35. All hydrocarbon control valves installed as part of the Cogeneration Project in Phase I and Phase II shall be equipped with live loaded packing systems and polished stems, or equivalent. (Basis: Cumulative Increase offsets)

36. All hydrocarbon valves shall be inspected per District Regulation 8, Rule 18 using a District approved leak detection device. Any valve found to be leaking in excess of 100 ppm shall be subject to the leak repair provisions of District Regulation 8, Rule 18. (Basis: RACT)

37. All connectors installed in the piping systems as a result of Phase I of the Cogeneration project shall be equipped with graphitic-based gaskets unless the service requirements prevent this material. Any connector found to be leaking in excess of 100 ppm shall be subject to the leak repair provisions of Regulation 8, Rule 18. (Basis: RACT, offsets, Cumulative Increase)

38. All new hydrocarbon centrifugal compressors installed as part of Phase I of the Cogeneration project shall be equipped with "wet" dual mechanical seals with a heavy liquid barrier fluid, or dual dry gas mechanical seals buffered with inert gas. All compressors shall be inspected and repaired in accordance with District Regulation 8, Rule 18. All compressors found to leaking in excess of 500 ppm shall be subject to the leak repair provisions of Regulation 8, Rule 18. (Basis: RACT, Offsets, Cumulative Increase)

39. All new fugitive equipment in organic service will be integrated into the owner's fugitive equipment monitoring and repair program and will meet the requirements of District Regulation 8-18. (Basis: Compliance monitoring)

40. The Cogeneration project consisting of S-1030, S-1031, S-1032, S-1033 shall consist of no more than 600 valves, 1800 connectors and 4 compressors. The POC emissions from these fugitive components shall not exceed 0.945 tons/year. The annual mass limit for POC may be adjusted based on final fugitive component count. Any additional POC offsets required due to a larger fugitive component count will need to be provided prior to permit issuance.

Contemporaneous Emissions reduction credit

41. The S-38 and S-39 steam boilers shall be completely shutdown no later than 90 days after startup of the S-1030 and S-1031 power train. (Basis: offsets)

42. The S-41 steam boilers shall be completely shutdown no later than 90 days after startup of the S-1032 and S-1033 power train. (Basis: offsets)

V Recommendation

The APCO has concluded that the proposed Valero Cogeneration Project, which is composed of the sources listed in Phase I (Application number 2488) and Phase II (Application number 2695), complies with all applicable District rules and regulations. The following sources in the Cogeneration project will be subject to the permit conditions, and BACT and offset requirements discussed previously.

S-1030 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

S-1031 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-60 Selective Catalytic Reduction (SCR) System and A-61 CO Oxidizing Catalyst System

S-1032 Combustion Turbine Generator: General Electric, Model LM 6000, 500 MM Btu/hr maximum rated capacity, Refinery Fuel Gas and/or Natural Gas Fired; water injected low NOx Burners; Abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

S-1033 Heat Recovery Steam Generator (HRSG): Duct Burner Supplemental Firing System, 310 MM Btu/hr maximum rated capacity; abated by A-62 Selective Catalytic Reduction (SCR) System and A-63 CO Oxidizing Catalyst System

EXEMPTION

Exempt Wet Cooling Tower: 540,000 air flow rate, 5600 gpm water circulation rate(Exempt per Regulation 2-1-128.4: Water cooler tower not used for evaporative cooling of process water)

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